2013 Interim Results Presentation

19 February 2013

contact

Six months ended 31 December 2012

Dennis Barnes, Chief Executive Officer

Graham Cockroft, Chief Financial Officer

Contact Energy - highlights

Contact Energy is one of New Zealand's largest electricity generators and retailers, and owns and operates geothermal, hydro and thermal electricity plants across New Zealand that support homes and businesses.

Contact Energy owns and operates **11 power stations** throughout New Zealand

166 MW (gross) of geothermal generation under construction

New Zealand's only underground gas storage at **Ahuroa, Taranaki**

4 geothermal stations in the central North Island

Supplies 23% of the New Zealand electricity retail market (at 31 December 2012)

4 thermal generation stations, located in Taranaki, Auckland, the Waikato and Hawke's Bay, provide capacity and backup to New Zealand's largely renewable generation

2 hydro power stations at Roxburgh and Clyde

Employs around **1,100** staff from Auckland to Invercargill

Generates around 1/4 of New Zealand's electricity

Contact Energy Group had net assets of **$3.5 billion** at 31 Dec 2012

Contact Energy is one of New Zealand's largest publicly listed companies by market capitalisation and is widely held, with **around 75,000 shareholders**

Contact has approximately: **568,000+** customers

across Contact Energy's electricity, gas and LPG businesses

Disclaimer

This presentation may contain projections or forward-looking statements regarding a variety of items. Such forward-looking statements are based upon current expectations and involve risks and uncertainties.

Actual results may differ materially from those stated in any forward-looking statement based on a number of important factors and risks.

Although management may indicate and believe that the assumptions underlying the forward-looking statements are reasonable, any of the assumptions could prove inaccurate or incorrect and, therefore, there can be no assurance that the results contemplated in the forward-looking statements will be realised.

EBITDAF and underlying earnings are non-GAAP (generally accepted accounting practice) profit measures. Information regarding the usefulness, calculation and reconciliation of EBITDAF and underlying earnings is provided in the supporting material.

Furthermore, while all reasonable care has been taken in compiling this presentation, Contact accepts no responsibility for any errors or omissions.

This presentation does not constitute investment advice.

Agenda

1. **Result highlights**	Dennis Barnes
2. **Operational review**	Dennis Barnes
3. **Financial performance**	Graham Cockroft
4. **Strategy update**	Dennis Barnes

Supplementary information

Solid results with improvement across all key financial metrics
Resumption of cash dividend

	6 months ended 31 Dec 2012	
EBITDAF[1]	$253m	up 10% from $231m
Profit for the period	$88m	up 29% from $68m
Earnings per share (cents)	12.2 cps	up 26% from 9.7cps
Net items excluded from underlying earnings after tax	($4m)	down from ($8m)
Underlying earnings after tax[1]	$92m	up 21% from $76m
Underlying earnings per share (cents)	12.7 cps	up 17% from 10.9 cps
Interim dividend (cents)	11 cps	stable
Operating cashflow after tax[1]	$177m	up 33% from $133m
Capital expenditure	$188m	down 32% from $276m

[1] Refer to slides 35-39 for a definition and reconciliation of non-GAAP measures.

The business is better able to manage changes in the operating environment

- In a highly competitive retail market volumes remain stable, with sales margins lower as a result of sustained competition
- Increasingly diverse fuel and asset portfolio responded as hydro volumes increased
  - base load thermal plant turned down
  - peakers provided capacity support for hydro
- Key capital projects progressing well
- Maintenance arrangements for Otahuhu and Taranaki combined-cycle power stations restructured, gas contracting discussions continue
- Focus on sustainable cost reduction and operational efficiency
- Programme to sell non-core assets advanced
- Safety statistics flat, prompting increased effort to achieve our Zero Harm aspiration

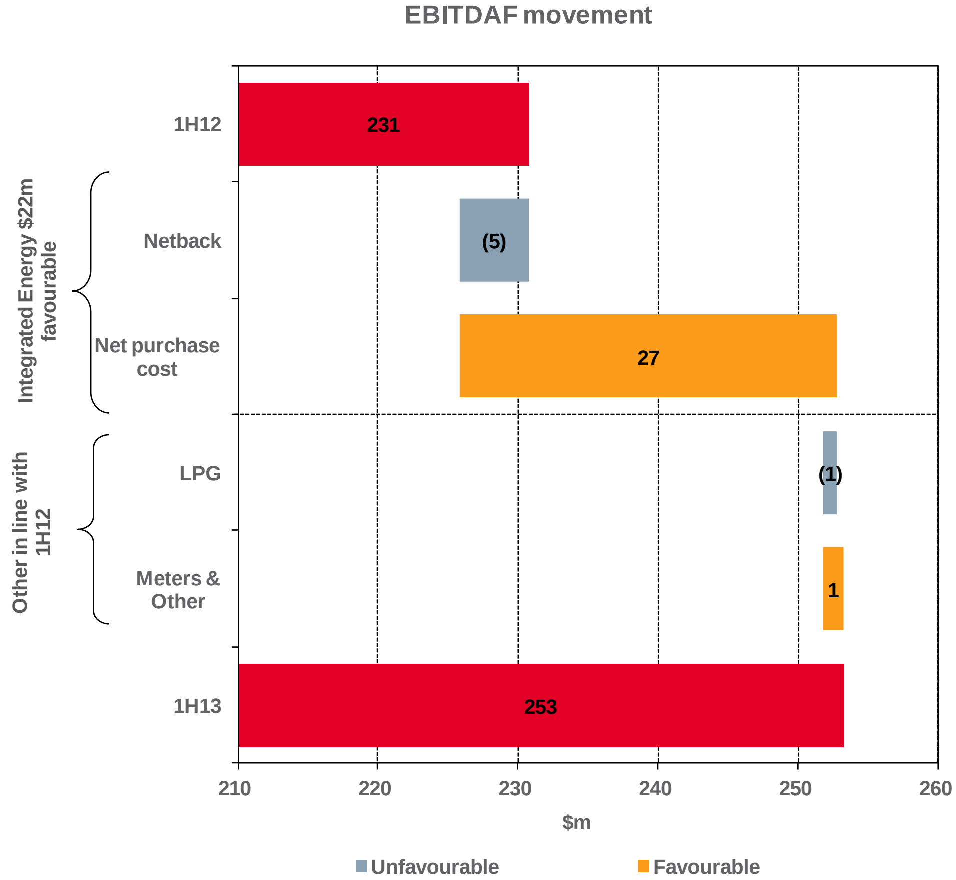
Margin reductions more than offset by lower costs as a result of increasingly diverse asset and fuel position

Integrated Energy segment EBITDAF: up $22m (11%) to $231m:

- **Netback:** unfavourable $5m (1%)
- **Net purchase cost:** favourable $27m (11%)

Other segment EBITDAF: stable at $22m:

- **LPG:** unfavourable $1m due to higher purchase costs
- **Other:** favourable $0.3m with increased meter costs more than offset by other revenue



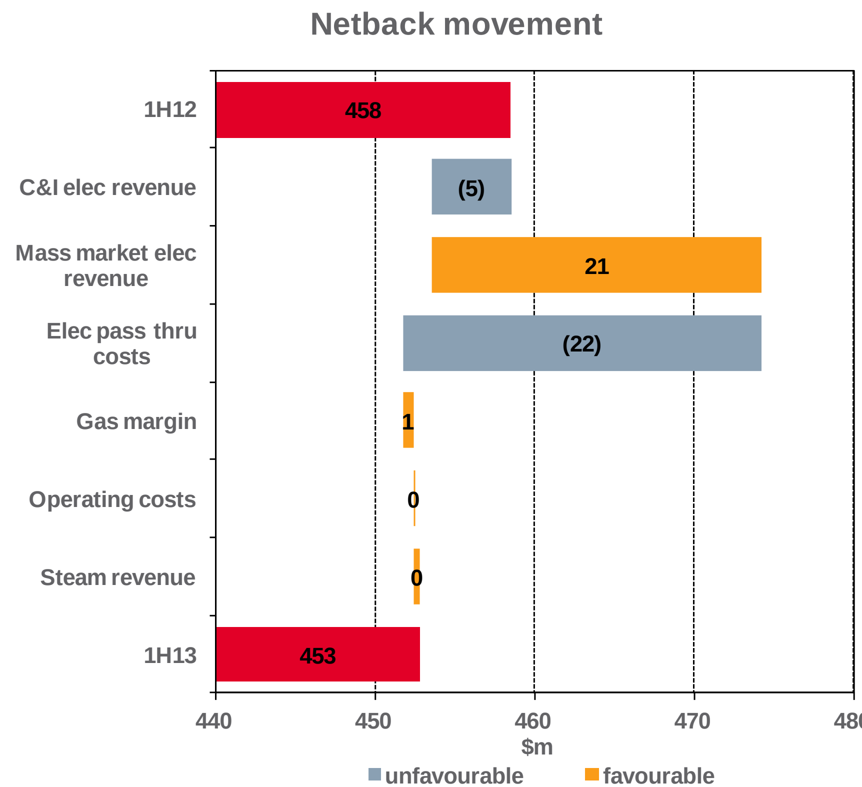
Operational review

Dennis Barnes

Netback – $5m lower (1%) to $453m

Stable customer base; margins reduce through sustained competition

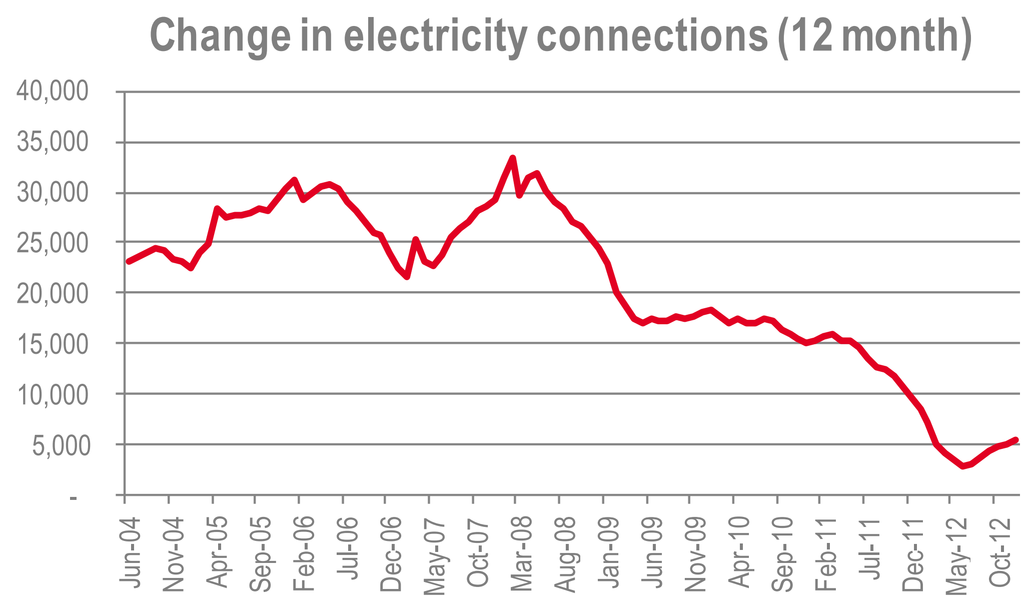
- Netback down $1/MWh to $90/MWh
- C&I revenue down $5m
  - Sales marginally down 11 GWh to 2,053 GWh
  - Average tariffs down $2/MWh due to lower wholesale prices
- Mass market revenue up $21m
  - Sales marginally down 16 GWh to 2,207 GWh
  - Average tariff up $11/MWh (5%), recovering network costs
- Electricity pass-through costs up $22m
  - Network charges up $6/MWh (9%), mass market up $9/MWh
- Gas margin up $1m
  - Gas volumes stable at 1.4 PJ, customer numbers up 2,500



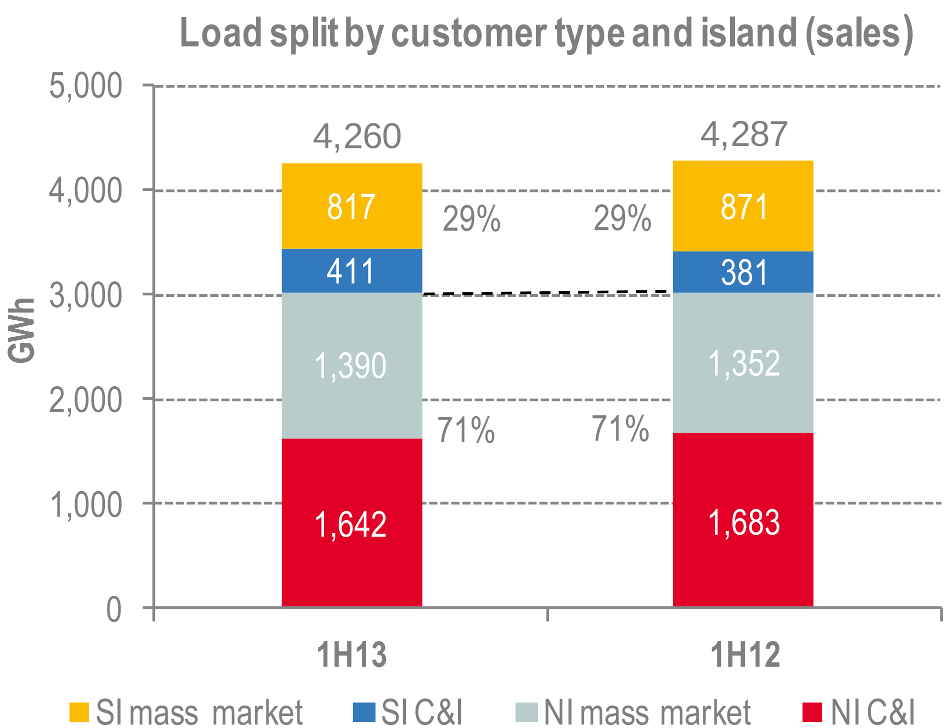
National demand remains suppressed; early signs of improvement

	6 months ended 31 Dec 2012 GWh	6 months ended 31 Dec 2011 GWh	Variance GWh	Variance %
North Island	12,739	12,800	(61)	(0%)
South Island ex Tiwai	4,750	4,722	28	1%
Tiwai	2,407	2,721	(314)	(12%)
Total national demand	**19,896**	**20,243**	**(347)**	**(2%)**

- National demand excluding Tiwai stable
- Tiwai demand down 314 GWh (12%). Increased demand from January 2013
- Early signs of growth
  - Christchurch demand up 177 GWh (16%)
  - Upward trend in new connections following four consecutive years of decreases

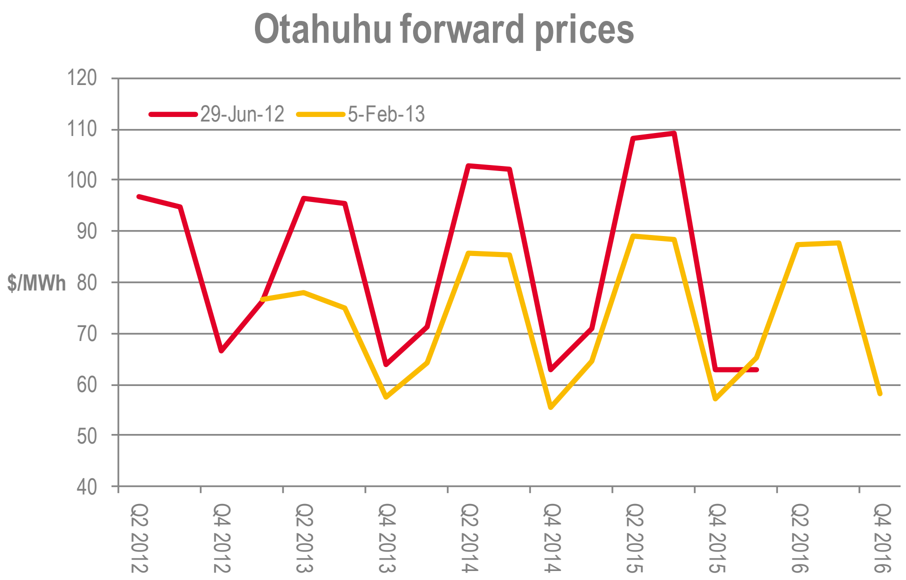


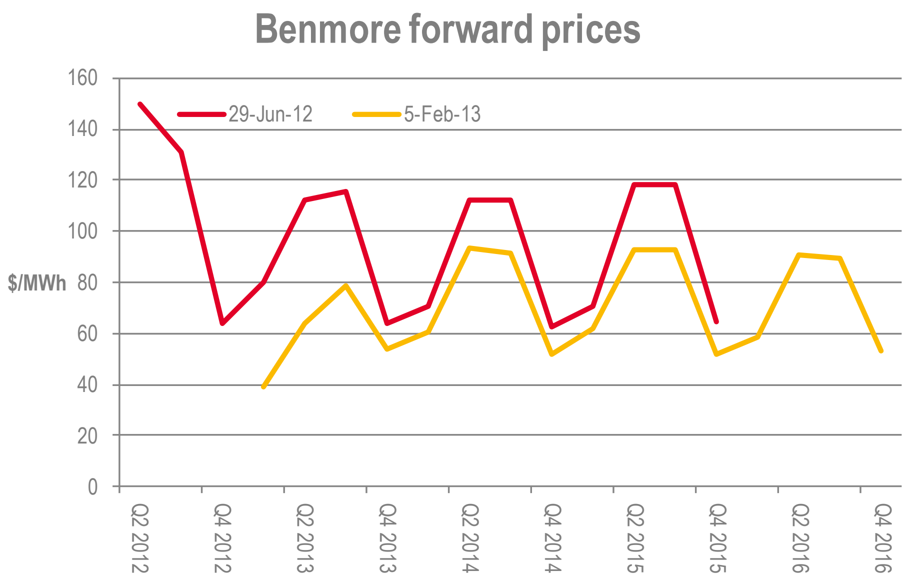
Contact has consolidated its electricity, gas and LPG market share



- Retail customer numbers remain stable
  - Electricity customer numbers stable at 442,500; OLOT customers 177,000 (+17,000 from 30 June 2012)
  - Retail gas customers up 2,500 from 31 December 2011 to 63,000
- Market churn is circa 20% with 30,000 customers per month switching
- C&I sales marginally down 11 GWh to 2,053 GWh
- LPG sales increased 5 per cent compared with1H12 due to increasing franchise customer numbers and the continued recovery of reticulated demand in Christchurch
- Retail Transformation project ‘go-live’ planned for later in CY13

The forward price curve has fallen over the last 6 months as the current oversupply impact is forecast to continue

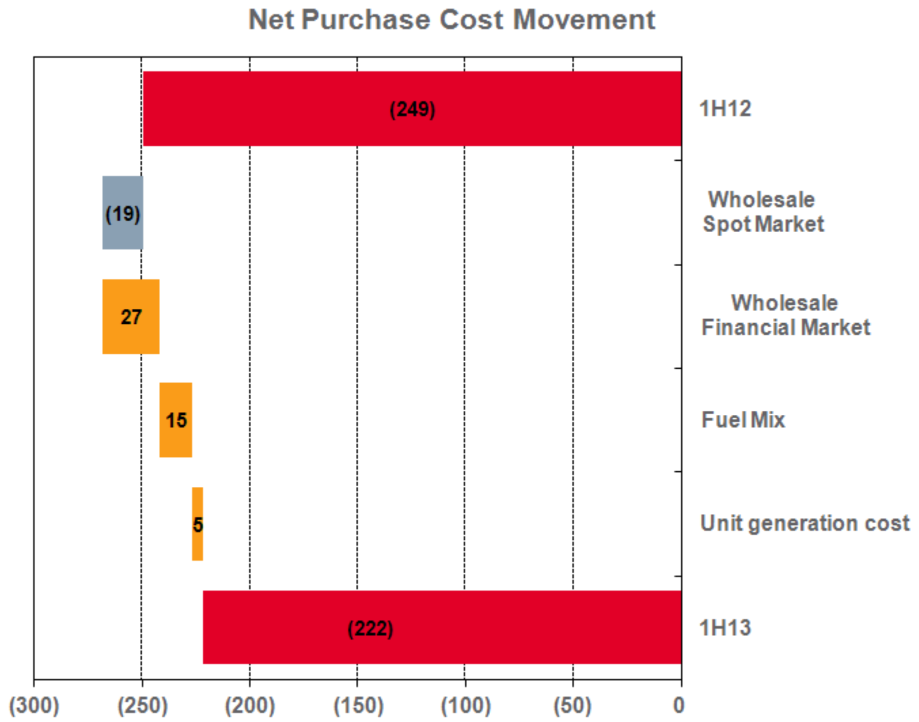




Source: http://d-cyphatrade.com.au

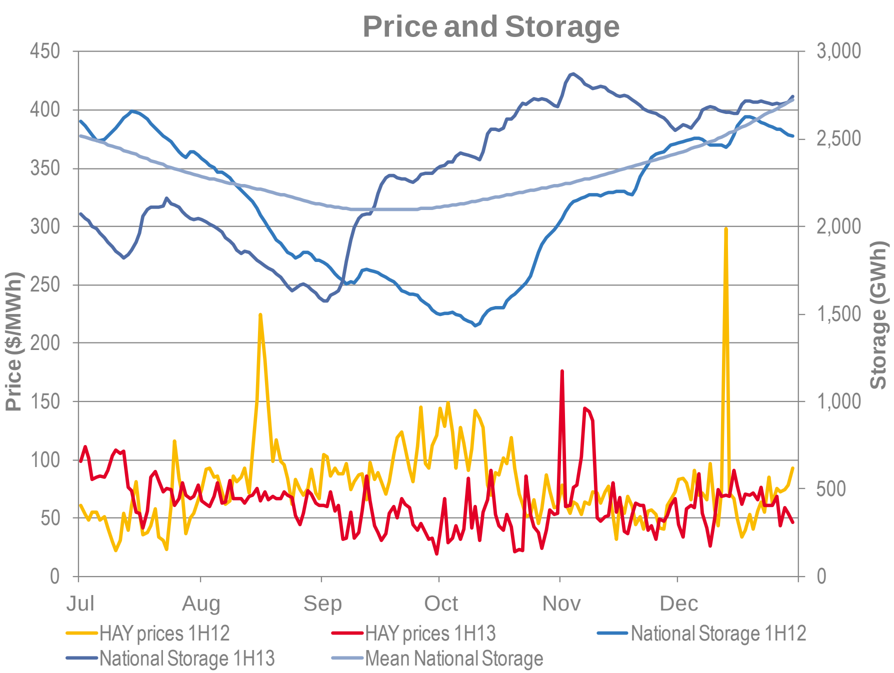
Net purchase cost – favourable $27m (11%) to –$222m

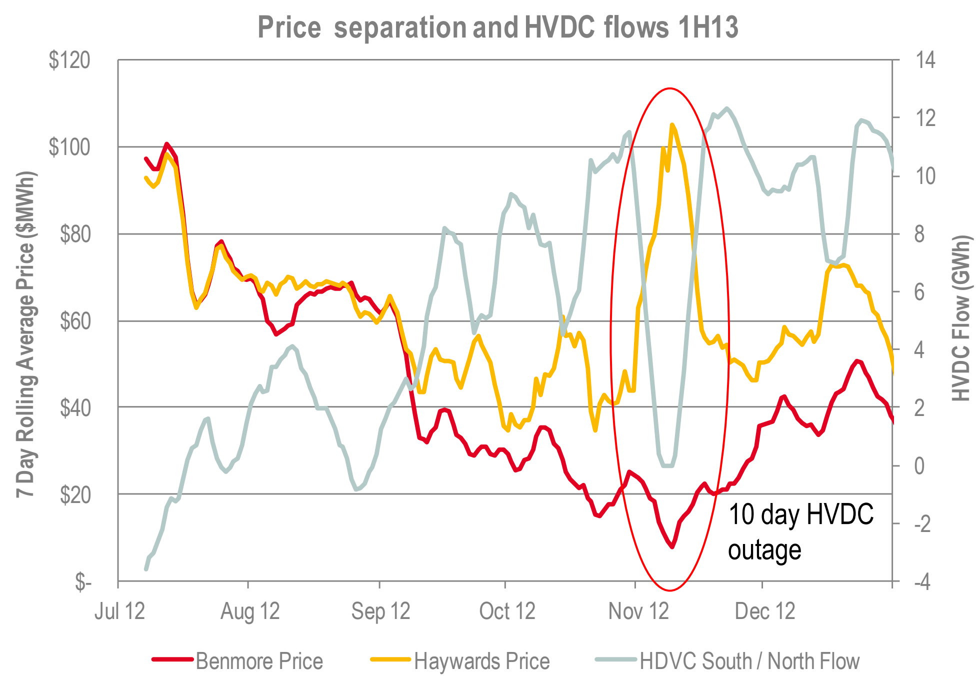
Diverse fuel and asset portfolio more than offsets impact of lower wholesale prices and price separation



- Wholesale spot market down $19m
  - GWAP down $23/MWh to $56/MWh, exposed volumes down 20%
  - LWAP down $21/MWh; purchases down 61 GWh
  - Location costs increased $2/MWh
- Wholesale financial market up $27m
  - CfDs up 121 GWh providing an effective hedge against lower wholesale prices
  - Ancillary services capability covered position and supported market
- Fuel mix up $15m
  - Low cost hydro generation displaced thermal generation. Gas usage down 2.3 PJ (13%)
- Unit generation cost down $5m
  - Lower carbon unit price partially offset by increased HVDC charges

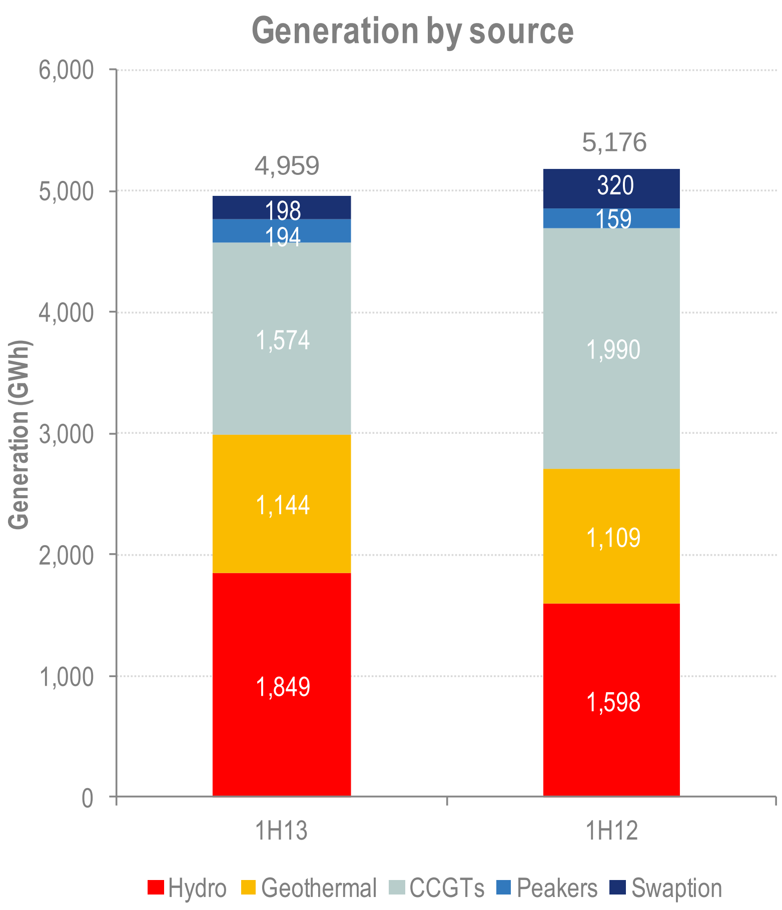
Wholesale price down $23/MWh to $56/MWh due to generally higher storage levels and increased hydro generation





- Inter-island price separation increased $2/MWh driven by HVDC capacity constraints and North Island reserve costs
- HVDC pole 3 commissioning in mid-2013

Flexibility of portfolio allows management of variable operating conditions



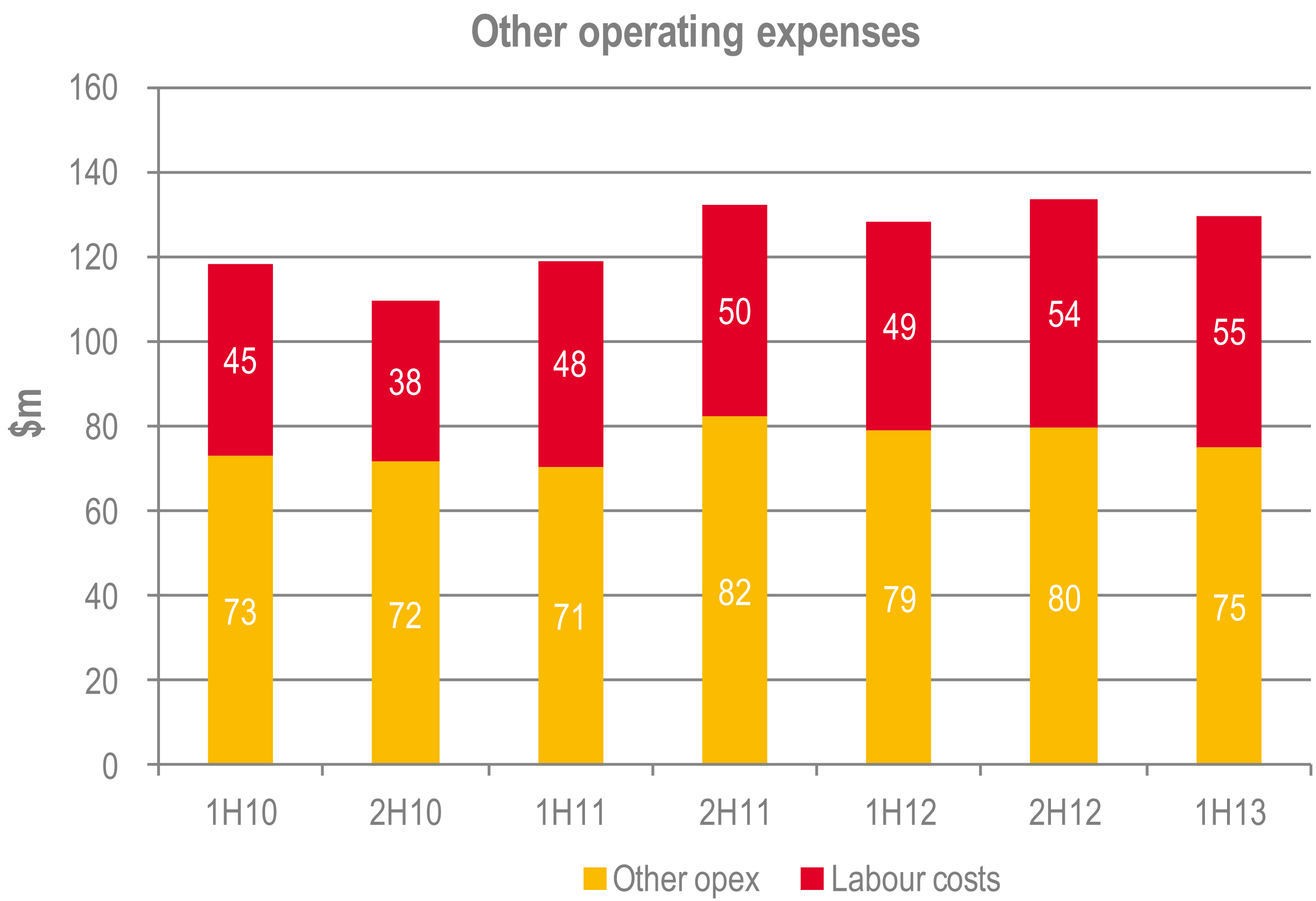
- More flexible fuel allows less thermal generation while hydro volumes increase
  - Hydro generation was up 251 GWh (16%) as higher rainfall resulted in increased tributary flows
  - Geothermal generation was down 25 GWh to 1,144 GWh as a number of outages due to Te Mihi commissioning works
  - Generation from the combined-cycle gas-fired power stations decreased 416 GWh to 1,574 GWh. Lower wholesale prices and a reduction in gas take-or-pay constraints meant that it was often cheaper to purchase electricity off the spot market than it was to generate it
  - Major plant outage completed at Otahuhu adding 25,000 operating hours to the gas turbine
  - Stratford Peaker generation increased 33 GWh to 192 GWh, Whirinaki 2 GWh generation
  - Swaption volumes were 198 GWh, down 122 GWh

Stratford Peakers, Whirinaki and Ahuroa gas storage operating as expected

Peaker generation increased 35 GWh to 194 GWh in 1H13

- The peakers have increased Contact's ability to respond to market prices and manage portfolio risk, particularly during planned and unplanned outages of other plant
  - The average price received for generation from the peakers was $93 per MWh, a premium of 67 per cent over the average generation price
  - Greater participation and earnings from the ancillary services market
    - Reserves market – aids Clutha generation to flow north
    - Frequency keeping – reduced costs for all of the market
- Whirinaki ran on 31 days in the period successfully capping exposure to high prices
- Gas storage provided gas flexibility in November and December 2012 that was not available in the market. Net extractions in 1H13 were 1.7 PJ

Contact is focusing on its operational costs across all areas of spend



Contact continues to focus on health, safety and the environment
Total Recordable Injury Frequency rate stable at 5.9

- The safety of our employees, contractors and visitors to any Contact site is the company's highest priority
- 66% of staff and contractors trained in "leading towards zero harm" and "safety conversations"
- Tana Umaga continues as spokesperson for our Safety and Well-being campaign "Stay safe mate"

Financial performance

Graham Cockroft

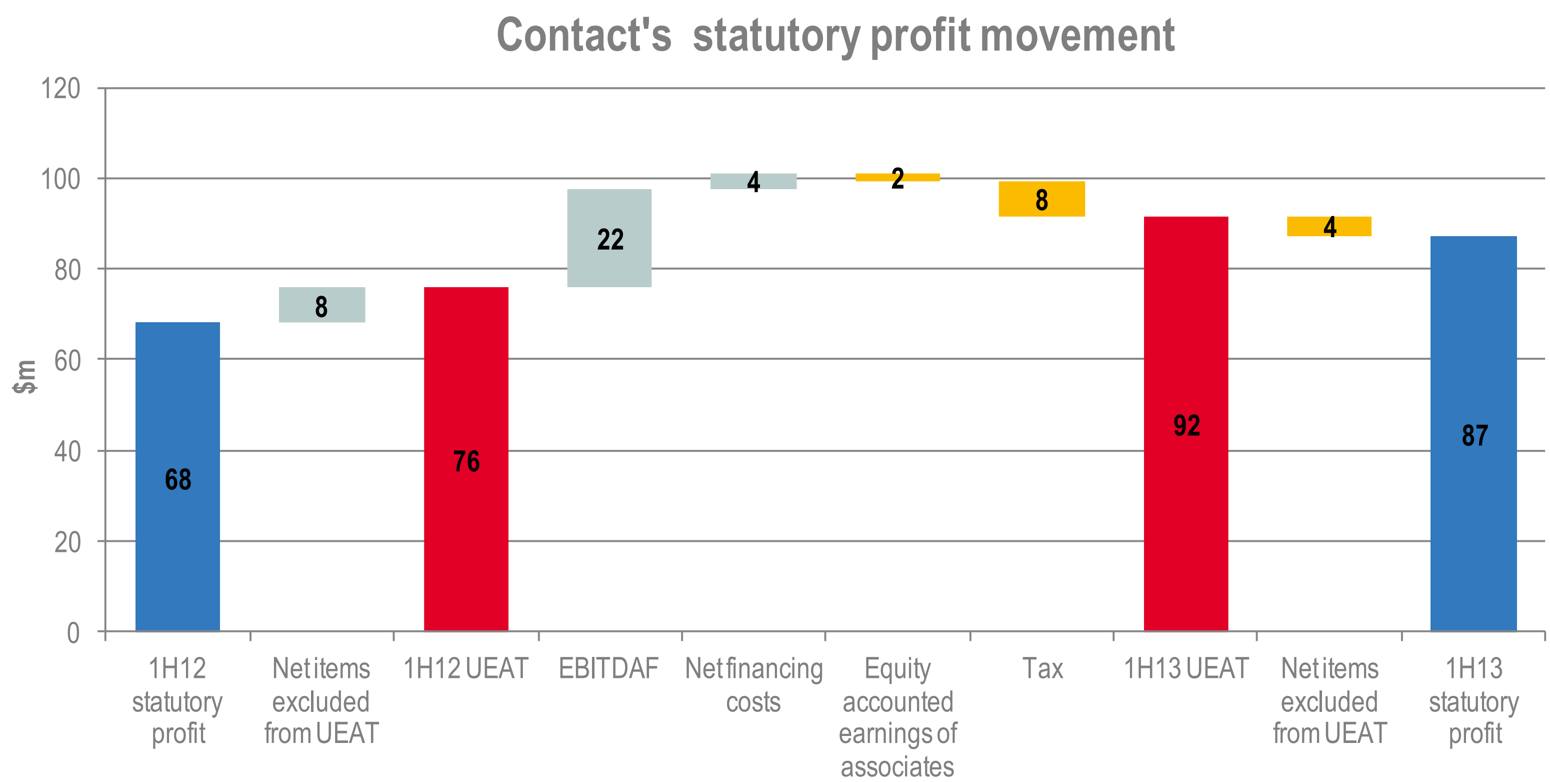
Underlying earnings per share up 17% and free cashflows up 45%

	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	variance $m	%
Profit for the period	88	68	20	29%
Earnings per share (cents)	12.2	9.7	2.5	26%
Revenue	1,213	1,283	(70)	(5%)
EBITDAF	253	231	22	10%
Underlying earnings after tax	92	76	16	21%
Underlying earnings per share (cents)	12.7	10.9	1.8	17%
OCAT	177	133	44	33%
Free cash flow per share	17.7	12.2	5.4	44%
Capital expenditure	188	276	(88)	(32%)

Reconciliation of Statutory Profit to Underlying earnings after tax

	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	%
Profit for the period	**88**	**68**	**20**	**29%**
Change in fair value of financial instruments	1	10	(9)	(90%)
Transition costs	3	1	2	200%
Clutha asset impairment and land sales	(2)	-	(2)	(100%)
Asset impairments	3	-	3	100%
Tax credit on underlying items	(1)	(3)	2	67%
Underlying earnings after tax	**92**	**76**	**16**	**21%**

Profit for the period up 29% from $68m to $88m
Underlying earnings after tax up 21% from $76m to $92m

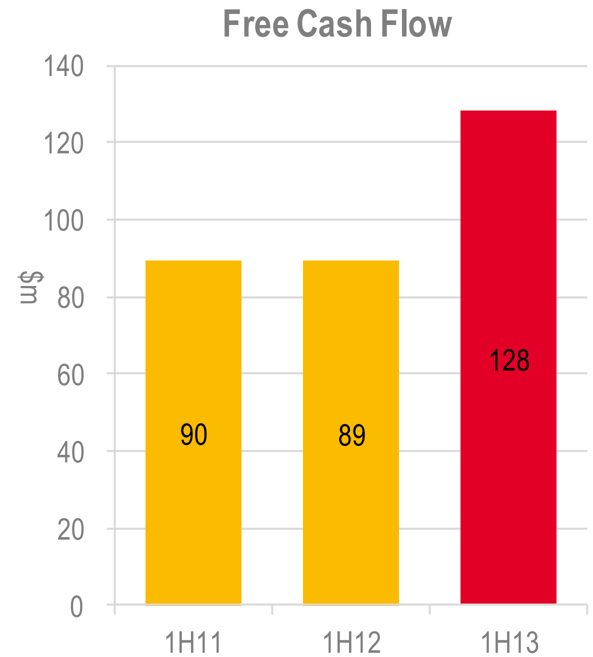


- Underlying earnings after tax increased 21%, primarily reflecting a 10% increase in EBITDAF and lower net financing costs; partially offset by the exit of the investment in Oakey Power Holdings Pty Limited in January 2012 and an increase in tax

Improved EBITDAF and working capital movements resulted in an increase in OCAT and free cash flow

	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	Variance %
EBITDAF	**253**	**231**	**22**	**10%**
Change in working capital	(15)	(48)	33	69%
Tax paid	(39)	(16)	(23)	(144%)
Other	5	9	(4)	(44%)
Operating cash flows	**204**	**176**	**29**	**16%**
Stay in business Capex	(27)	(43)	16	(37%)
OCAT[1]	**177**	**133**	**44**	**33%**
Net interest paid	(49)	(44)	(5)	11%
Free cash flow[2]	**128**	**89**	**39**	**44%**
Average Funds Employed (calendar year)	3,932	3,675	257	7%
OCAT Ratio (calendar year)	9.6%	7.6%	2.0%	26%

[1] Operating Cashflow After Tax
[2] Cash available to fund distributions to shareholders and growth capital expenditure



- Improved working capital driven by lower wholesale spot price in Dec 2012
- Higher tax paid due to increased final FY12 tax payment paid in July 2012
- Lower SIB capex spend following the completion of the Wairakei Bioreactor in FY12

- Refer to slide 39 for definitions

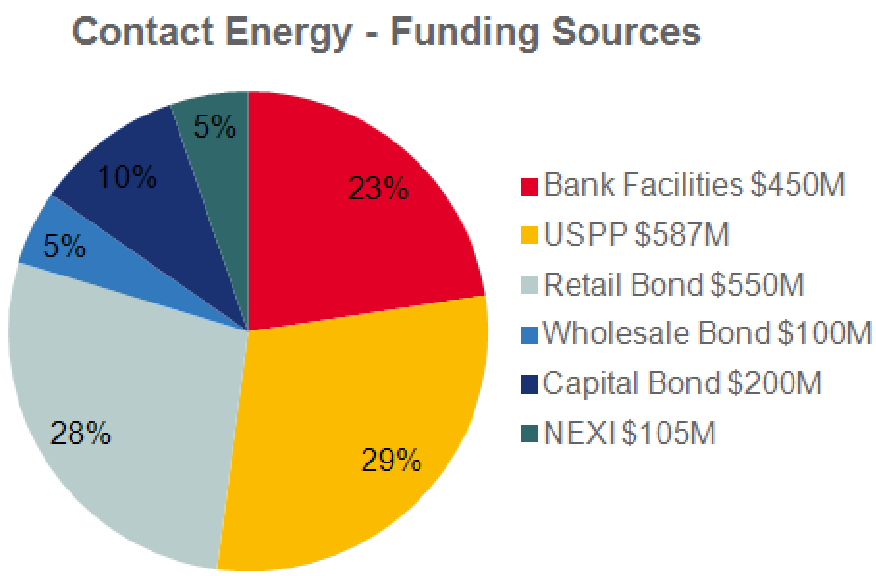
Financing costs increased by $4m, reflecting the investment in Wairakei Investment Programme and Retail Transformation project

	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m
Interest income	2	1
Interest expenses	(56)	(51)
Financing costs	**(54)**	**(50)**
Financing costs capitalised	21	13
Weighted average interest rate on borrowing	6.9%	7.6%

- Financing costs increased by $4m reflective of ongoing growth capex spend partially offset by interest income
- Lower weighted average interest rate fell as Contact took advantage of current rates to lower the overall rate on its hedging portfolio

Diversity of funding choices for 2014 refinancing

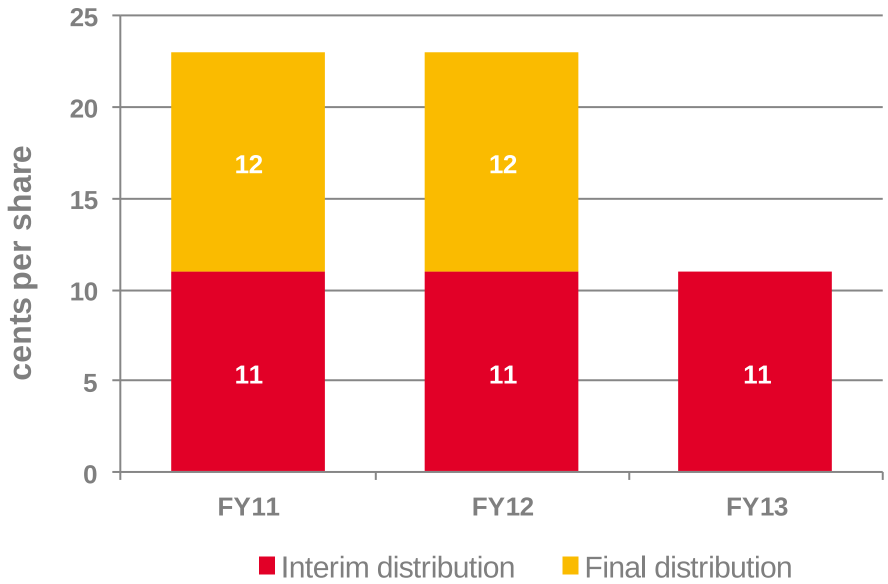
- Balance Sheet gearing level remains strong
  At 31 December 2012:
  - Net debt $1.5bn, up slightly on 31 December 2011
  - Gearing ratio 29.3%
  - $450m total committed bank facilities* ($33m drawn) plus $92m available under export credit agency facility (nil drawn)
  - Weighted average tenor of funding facilities 5.4 years
- Bank facilities were extended in November with the banking group widened, adding to potential capacity in this market
- Contact's diverse funding portfolio provides options for 2014 refinancing



* As at 31 December committed bank facilities totalled $450m of which $70m was not available to draw until mid-February 2013

As signalled, Contact has reverted to a fully imputed cash dividend

Interim dividend stable at 11 cps, a payout ratio of 87% of Underlying EPS



- 31 December 2012 total imputation credits available to be attached to a dividend are 236m
- Available subscribed capital at 31 December 2012 in excess of $1bn

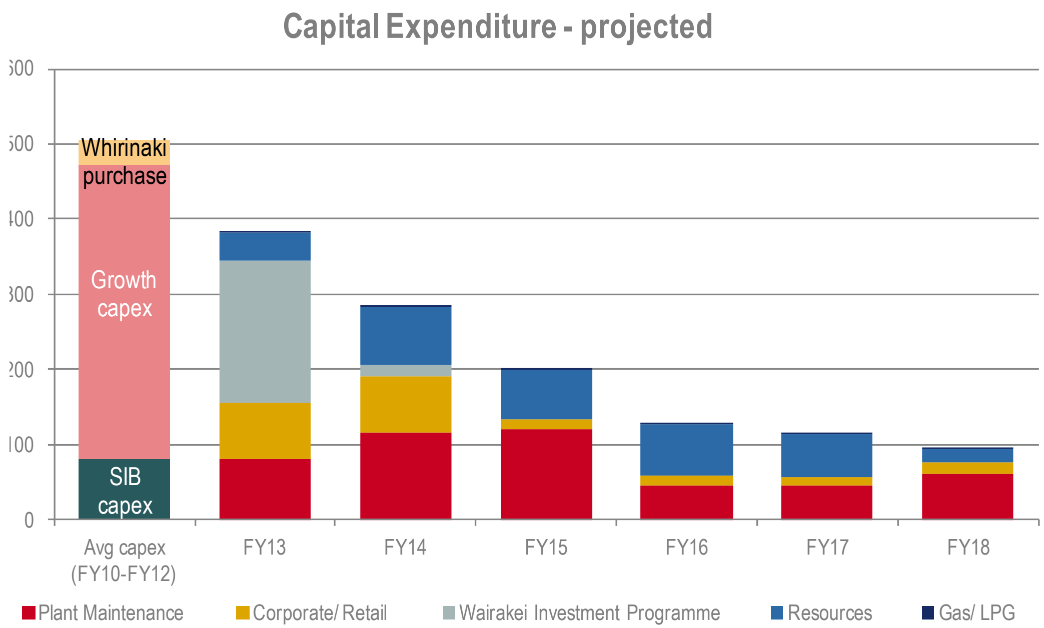
- Ex-dividend date: Wednesday, 6 March 2013
- Record date: Friday, 8 March 2013
- Payment date: Tuesday, 26 March 2013

Strategy update

Dennis Barnes

Significant growth capex finishes in FY14 with the completion of Te Mihi, which in turn releases free cash flow in FY14

- **Lower average cost of generation and increased portfolio flexibility**
  - 166 MW Te Mihi geothermal power station, completion mid-CY2013
  - Huntly swaption expired
  - Ahuroa bypass pipeline completion mid CY2013
- **Defining the optimal operating regime of the CCGTs continues**
  - No significant gas commitments made
  - "Plant maintenance" currently includes uncommitted major refurbishments for combined-cycle plants



- **Future development options maintained for when market signals improve**
  - Tauhara – New Zealand's next lowest cost generation development
  - Taheke development

The Wairakei Investment Programme continues to progress; will add 114 MW of additional renewable generation

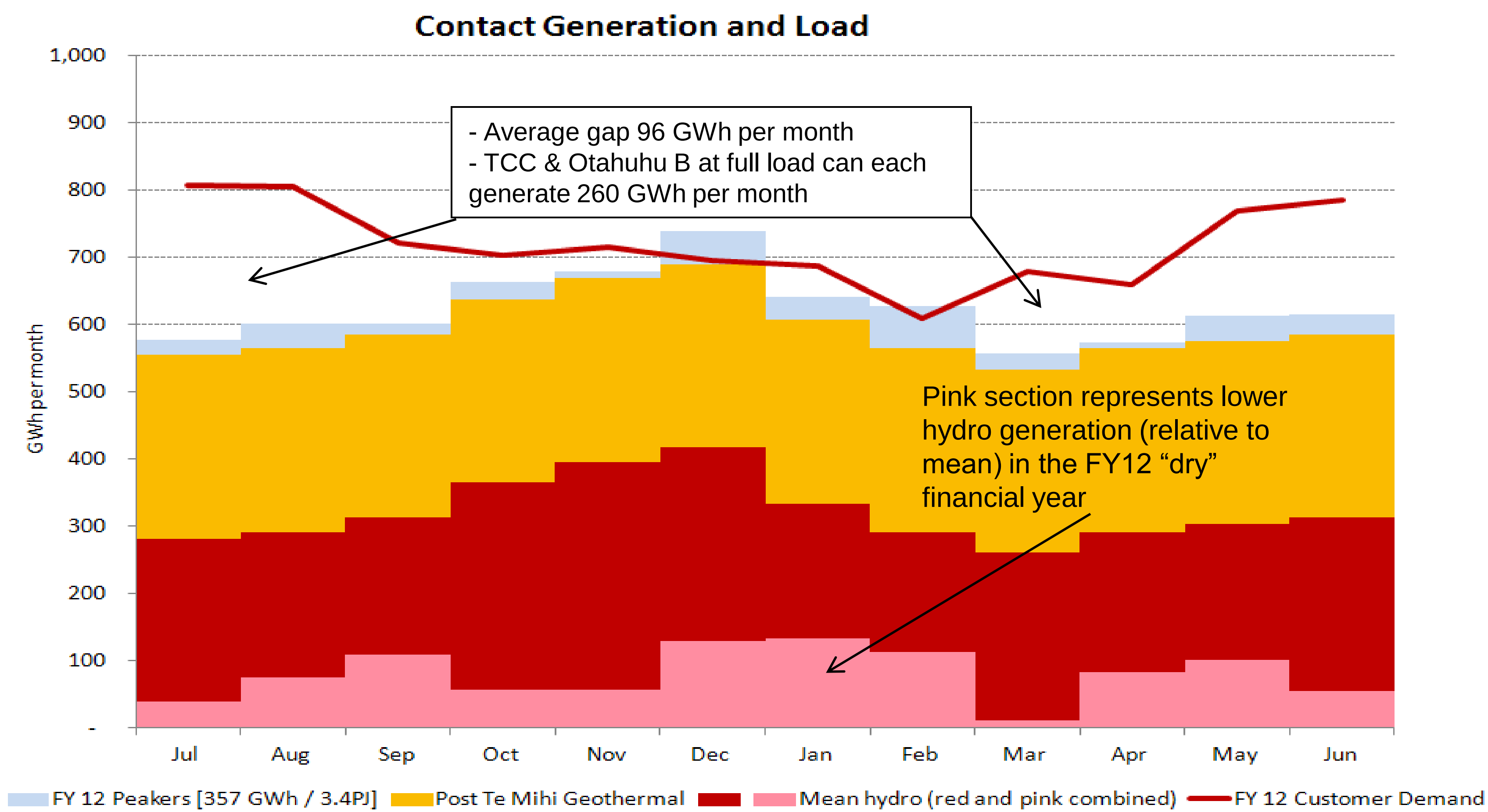
Project	Contractor	Due date	Status
Wairakei Steamfield Project	Hawkins	August 2011	Commissioned and operating to expectations
Wairakei Bioreactor Project	Downers	August 2012	Commissioned and operating to expectations
Te Mihi Steamfield Project	Downers	October 2012	Practically complete and currently in operation to meet the power station commissioning schedule. First steam blows at power station pre-Christmas 2012
Drilling (WRK and Te Mihi)	Century	2013	All new wells complete
Te Mihi Power Station Project	MSP JV	2013	Construction well advanced. Commissioning commenced
Operational Preparedness	Internal	2013	On target. Operators recruited

Unit 1 turbine & generator installation works

Te Mihi site looking east out of turbine hall

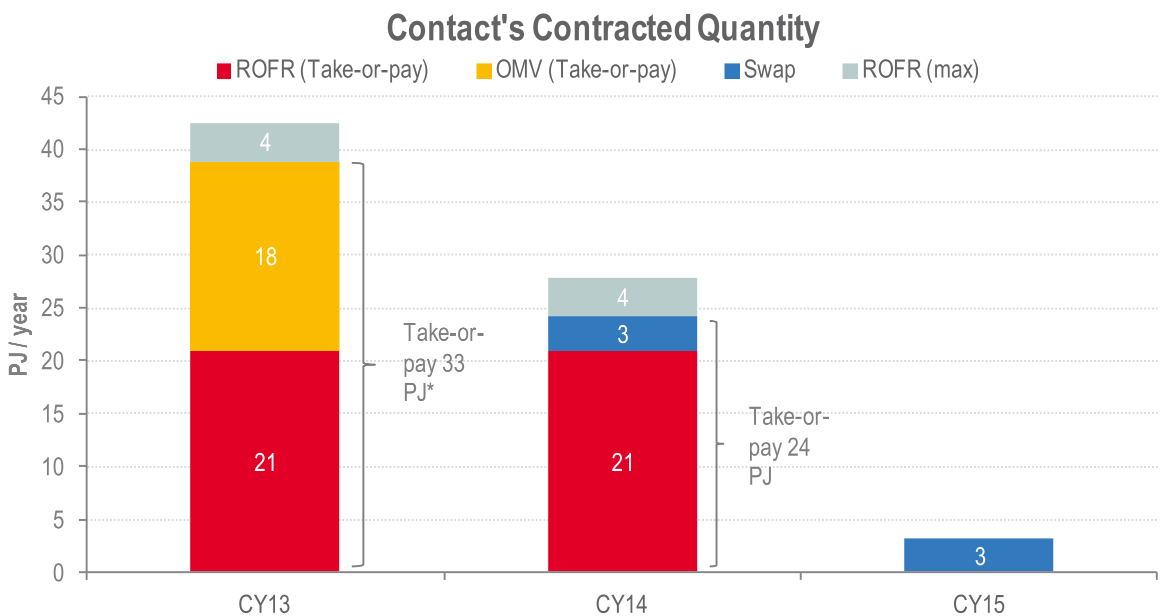
Steam field dump station being used for the first time

Contact's generation is increasingly renewable with flexibility around the future role of thermal



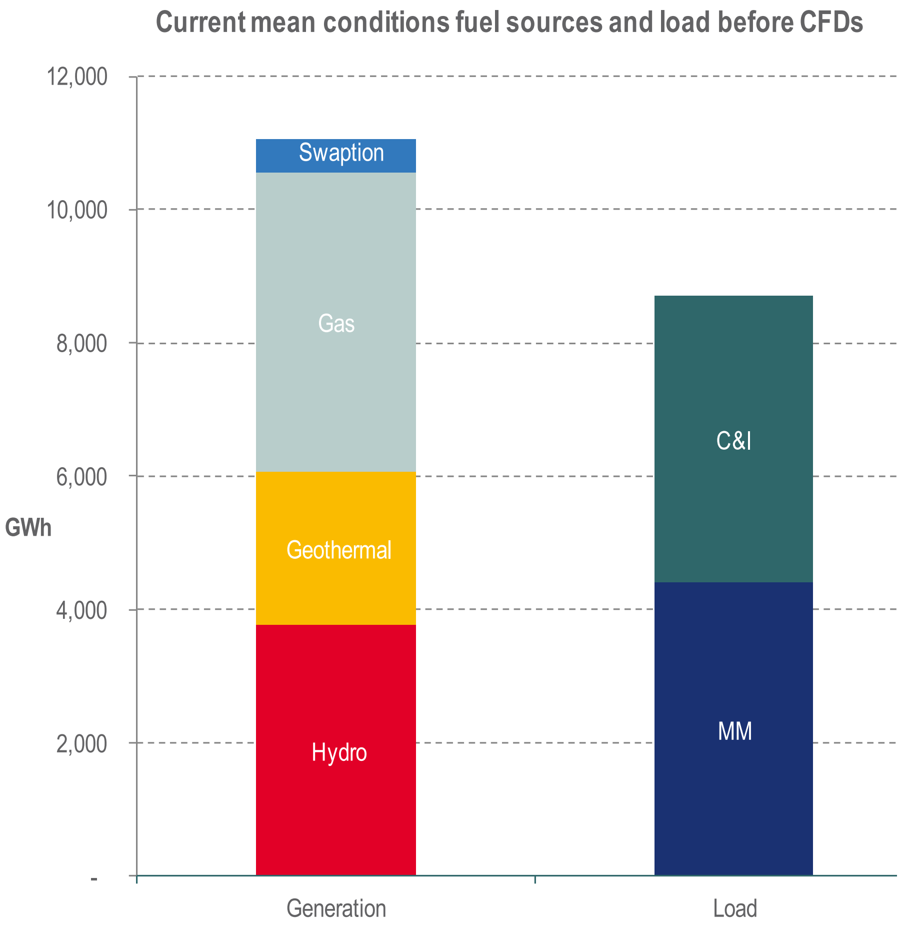
Progress continues on lowering cost of goods sold

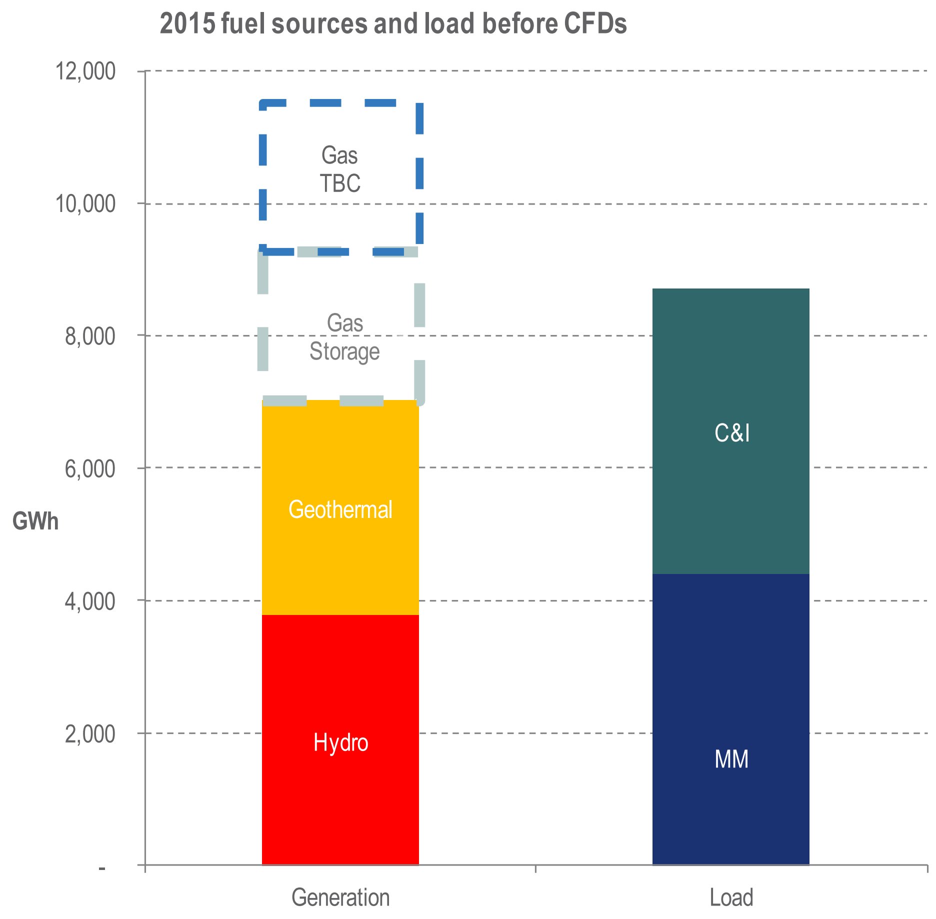
- New maintenance agreements for Otahuhu and Taranaki combined-cycle gas-fired power stations deliver lower costs, defer commitments to major maintenance and provide time to determine future operating regime
- Swaption ended 31 December 2012. First Huntly unit decommissioned
- No new gas commitments
- Gas pipeline between Ahuroa gas storage and the Stratford power stations progressing well
  - $15m capital spend will reduce operating costs and increase operating flexibility



* Includes gas sale and repurchase arrangement of 5 PJ in CY13

Reshaping contracted gas volumes from 2H14 will allow Contact to flexibly match its retail sales





Summary

- Solid first half performance
  - Stable volume and customer numbers reflect competitive retail offerings
  - Margins lower as continued generation oversupply drives competition
  - Reducing cost of generation from diverse fuel and asset portfolio
  - Cost control
- Cost base and structure of the business adjusting to match the flat outlook for energy demand, covering all areas including procurement, IT and people. Focus to increasingly move to the customer
- Major projects and divestments progressing with the end of the current capital programme in sight
- Positioned to make the right portfolio decisions with plant maintenance agreements restructured and no new gas commitments

Supporting material

Non-GAAP profit measures – EBITDAF

- EBITDAF is Contact's earnings before net interest expense, tax, depreciation, amortisation, change in fair value of financial instruments and other significant items.
- Management and directors monitor EBITDAF as a key indicator of Contact's performance at segment and Group levels and believe it assists investors to understand the performance of the core operations of the business.
- Reconciliation of EBITDAF to reported profit:

	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	Variance %
EBITDAF	**253**	**231**	**22**	**10%**
Depreciation and amortisation	(95)	(95)	-	0%
Change in fair value of financial instruments	(1)	(10)	9	90%
Other significant items	(4)	(1)	(3)	(300%)
Equity accounted earnings of associate	-	2	(2)	(100%)
Net interest expense	(33)	(37)	4	11%
Tax expense	(32)	(22)	(10)	(45%)
Profit for the period	**88**	**68**	**20**	**29%**

The numbers in the table have been extracted from Contact's reviewed financial statements.

- Depreciation and amortisation, change in fair value of financial instruments, net interest and tax expense are explained in the following slide. Other significant items are explained in the following slides on underlying earnings.

Explanation of reconciliation between EBITDAF and profit for the period

- The adjustments from EBITDAF to reported profit are as follows:
  - Depreciation and amortisation: Costs of $95 million are unchanged.
  - Change in fair value of financial instruments: Current period movement predominantly driven by the release of the residual mark to market value of the Huntly swaption on maturity. This compares with an unfavourable movement of $10 million in 1H12 as a result of a downward shift in New Zealand interest rates.
  - Equity accounted earnings of associate: Decline of $2m compared with 1H12 is due to the exit of the investment in Oakey Power Holdings Pty Limited in January 2012.
  - Net interest expense: Decreased by $4 million (11 per cent) to $33 million due to capitalised interest increasing by $8 million as development of the Te Mihi power station continued, partially offset by a $5 million increase in interest expense in relation to the capital bond issue in December 2011.
  - Tax expense: Represents an effective tax rate of 26 per cent, which is lower than the statutory rate of 28 per cent, principally due to the release of part of the deferred tax liability recognised in relation to the held for sale New Plymouth plant site offset by the non-deductibility of impairment losses on held for sale land.
  - Other significant items explained in a following slide.

Non-GAAP profit measures – underlying earnings

- Underlying earnings after tax are calculated by adjusting reported profit for the year for significant items that do not reflect the ongoing performance of the Group.
- Significant items are determined in accordance with the three principles of consistency, relevance and clarity. Transactions considered for classification as significant items include impairment or reversal of impairment of assets, fair value movements in financial instruments, business integration and acquisition costs, and transactions or events outside of Contact's ongoing operations that have a significant impact on reported profit.
- Management and directors monitor underlying earnings as a basis for determining dividends and believe it assists investors to understand the ongoing performance of the business.
- Underlying earnings is not included in Contact's segment reporting disclosures in the financial statements as debt funding and tax expense are managed at a Group level.
- Reconciliation of reported profit to underlying earnings:

	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	%
Profit for the period	**88**	**68**	**20**	**29%**
Change in fair value of financial instruments	1	10	(9)	(90%)
Transition costs	3	1	2	200%
Clutha asset impairment and land sales	(2)	-	(2)	(100%)
Asset impairments	3	-	3	100%
Tax credit on underlying items	(1)	(3)	2	67%
Underlying earnings after tax	**92**	**76**	**16**	**21%**

The numbers in the table have been extracted from Contact's reviewed financial statements.

Non-GAAP profit measures – explanation of reconciliation from reported profit to underlying earnings

- The adjustments from reported profit to underlying earnings are as follows:
  - The change in fair value of financial instruments that do not qualify for hedge accounting.
  - Transition costs arising on implementation of Enterprise Transformation and associated activities in the Retail business.
  - As a result of the decision not to proceed in the foreseeable future with any of the options being investigated for hydro generation development on the Clutha River, the project development costs have been impaired and some of the associated land has been sold.
  - Tax adjustments in relation to the above.

- Underlying earnings after tax: The adjustments have been the subject of a review by the auditors pursuant to New Zealand Institute of Chartered Accountants (NZICA) Review Engagement Standards RS-1.

Operating cashflow after tax (OCAT) and OCAT ratio

- Contact uses OCAT and OCAT ratio as an internal measure of the cash generating performance of the business
- Key difference between OCAT and statutory cash flows from operating activities is OCAT includes stay-in-business capex

OCAT ratio

- Measures Contact's cash returns generated from productive funds employed within operations
- Calculated on a 13 month weighted average basis

  OCAT ratio = (OCAT – interest tax shield)/Average funds employed
- Interest tax shield adjustment accounts for the reduction in tax due to interest paid

Average fund employed

- Measures funds employed by Contact in the operating assets of the business, excluding capital work in progress that is not yet operational
- Calculated on a 13 month weighted average basis to match the operating asset base to operational cash flows

Reconciliation of net assets to productive capital

Net assets
Less:
Cash
Derivative financial instruments - assets
Capital Work in Progress
Add:
Debt (NZD equivalent of notional borrowings – after foreign exchange hedging and before deferred financing fees
Derivative financial instruments - liabilities
Fund employed (13 month weighted average)

18 months operational statistics

Data		Measure	The month ended 31 July 2011	The month ended 31 August 2011	The month ended 30 September 2011	The month ended 31 October 2011	The month ended 30 November 2011	The month ended 31 December 2011
Netback	Mass market electricity sales	GWh	414	431	390	350	332	306
	Commercial & industrial electricity sales	GWh	317	346	345	354	353	348
	Retail gas sales	GWh	86	98	75	63	45	40
	Steam sales	GWh	23	67	68	65	67	68
	Total retail sales	GWh	840	942	878	833	797	762
	Average electricity sales price	$/MWh	200.57	187.81	175.77	168.88	162.13	161.63
	Electricity direct pass thru costs	$/MWh	70.74	65.31	65.67	61.65	60.30	58.06
	Electricity and gas cost to serve	$/MWh	11.53	10.67	10.71	11.20	12.48	9.04
	Netback[1]	$/MWh	106.60	97.44	87.67	85.47	80.49	85.59
	Actual electricity line losses	%	10%	5%	-1%	1%	5%	7%
	Retail gas sales	PJ	0.3	0.3	0.2	0.2	0.1	0.2
	Electricity customer numbers [6]		438,500	438,500	439,500	441,000	442,500	443,000
	Gas customer numbers [6]		59,000	59,500	59,500	60,000	60,500	60,500
Net Purchase Cost	Thermal generation	GWh	427	471	458	322	251	220
	Geothermal generation	GWh	187	206	192	201	178	205
	Hydro generation	GWh	243	217	204	307	340	287
	Spot market generation	GWh	857	893	855	831	768	712
	Swaption	GWh	34	80	59	61	33	54
	Spot electricity purchases	GWh	806	805	721	702	715	695
	CfD sales	GWh	22	14	30	36	17	28
	GWAP [2]	$/MWh	52.45	96.53	95.97	96.05	57.28	70.42
	LWAP [3]	$/MWh	55.48	103.09	100.37	101.69	64.68	79.24
	LWAP/GWAP	%	106%	107%	105%	106%	113%	113%
	Gas used in internal generation	PJ	3.4	3.8	3.6	2.8	2.2	2.1
	Wholesale gas sales	PJ	0.1	0.2	0.3	0.3	0.3	0.2
	Gas storage net movement	PJ	0.5	0.3	0.1	0.1	0.7	0.1
	Unit generation cost [4]	$/MWh	54.47	56.73	56.97	46.58	44.22	38.01
	Net purchase cost [5]	$/MWh	61.57	54.55	50.13	39.59	48.36	40.31
LPG	LPG sales	tonnes	6,911	7,200	6,096	5,603	4,575	4,653
	LPG customer numbers (includes franchises) [6]		59,500	59,500	59,500	60,000	60,000	60,000

[1] Netback margin equates to: (retail electricity, gas and steam sales less direct pass thru and cost to serve costs) / (total retail sales volume).

[2] This is the price received by Contact for its spot generation. It excludes contracts for differences (including swaption) and direct sales.

[3] This is the price paid by Contact for its spot electricity purchases. It excludes contracts for differences and other purchase costs.

[4] Unit generation costs equates to: (total generation fuel, transmission and operating costs) / (Spot market generation). Excludes gas purchases for wholesale and retail gas sales

[5] Net purchase cost equates to: (total wholesale revenue less unit generation costs and electricity & gas purchases) / (retail sales volume).

[6] Data has been rounded to the nearest 500 and reflects numbers as at month end.

18 months operational statistics

Data		Measure	The month ended 31 January 2012	The month ended 28 February 2012	The month ended 31 March 2012	The month ended 30 April 2012	The month ended 31 May 2012	The month ended 30 June 2012
Netback	Mass market electricity sales	GWh	294	268	318	317	357	411
	Commercial & industrial electricity sales	GWh	341	344	358	333	348	305
	Retail gas sales	GWh	35	34	40	46	58	76
	Steam sales	GWh	68	64	66	67	37	11
	Total retail sales	GWh	738	710	783	762	800	802
	Average electricity sales price	$/MWh	163.74	167.83	173.80	182.76	202.40	205.08
	Electricity direct pass thru costs	$/MWh	60.70	60.79	63.19	64.61	72.65	73.88
	Electricity and gas cost to serve	$/MWh	12.29	14.45	12.67	12.39	13.65	13.57
	Netback[1]	$/MWh	82.86	83.87	89.01	94.75	105.51	111.82
	Actual electricity line losses	%	9%	1%	2%	3%	9%	8%
	Retail gas sales	PJ	0.1	0.1	0.1	0.2	0.3	0.3
	Electricity customer numbers [6]		444,000	444,500	444,000	443,000	443,000	443,500
	Gas customer numbers [6]		60,500	61,000	61,500	61,500	62,000	62,500
Net Purchase Cost	Thermal generation	GWh	284	354	478	430	495	475
	Geothermal generation	GWh	206	196	207	205	187	201
	Hydro generation	GWh	200	180	249	210	201	258
	Spot market generation	GWh	690	729	933	844	883	933
	Swaption	GWh	23	94	31	14	87	53
	Spot electricity purchases	GWh	687	608	678	657	768	781
	CfD sales	GWh	9	45	202	107	105	112
	GWAP [2]	$/MWh	77.33	128.43	86.39	80.68	136.71	115.62
	LWAP [3]	$/MWh	82.55	143.39	91.65	87.60	150.40	129.84
	LWAP/GWAP	%	107%	112%	106%	109%	110%	112%
	Gas used in internal generation	PJ	2.5	3.0	3.7	3.5	4.3	3.7
	Wholesale gas sales	PJ	0.2	0.2	0.2	0.2	0.1	0.1
	Gas storage net movement	PJ	(0.0)	(0.0)	(0.2)	0.0	(0.0)	(0.0)
	Unit generation cost [4]	$/MWh	49.20	54.71	48.89	43.42	54.33	54.58
	Net purchase cost [5]	$/MWh	50.52	43.01	18.65	30.73	40.33	49.09
LPG	LPG sales	tonnes	4,238	4,194	4,140	5,067	6,384	6,654
	LPG customer numbers (includes franchises) [6]		60,500	60,500	60,500	61,000	61,500	61,500

18 months operational statistics

Data		Measure	The month ended 31 July 2012	The month ended 31 August 2012	The month ended 30 September 2012	The month ended 31 October 2012	The month ended 30 November 2012	The month ended 31 December 2012
Netback	Mass market electricity sales	GWh	465	428	365	340	304	305
	Commercial & industrial electricity sales	GWh	310	344	339	354	356	349
	Retail gas sales	GWh	92	85	67	56	47	42
	Steam sales	GWh	29	65	68	71	68	65
	Total retail sales	GWh	895	921	839	821	775	761
	Average electricity sales price	$/MWh	198.79	194.16	181.14	172.84	167.78	170.23
	Electricity direct pass thru costs	$/MWh	69.34	77.33	73.13	68.36	62.16	64.07
	Electricity and gas cost to serve	$/MWh	10.10	10.45	11.35	12.20	12.64	11.13
	Netback[1]	$/MWh	107.55	93.99	85.91	82.11	84.00	85.80
	Actual electricity line losses	%	4%	3%	6%	4%	5%	3%
	Retail gas sales	PJ	0.3	0.3	0.3	0.2	0.2	0.2
	Electricity customer numbers [6]		443,000	443,000	442,500	443,000	443,000	442,500
	Gas customer numbers [6]		62,500	63,000	63,000	63,500	63,500	63,000
Net Purchase Cost	Thermal generation	GWh	364	355	367	219	237	226
	Geothermal generation	GWh	205	197	170	193	189	190
	Hydro generation	GWh	285	235	343	369	289	328
	Spot market generation	GWh	854	787	880	780	715	744
	Swaption	GWh	63	53	-	22	44	17
	Spot electricity purchases	GWh	801	786	735	714	681	666
	CfD sales	GWh	76	81	75	5	18	14
	GWAP [2]	$/MWh	78.72	64.02	45.18	39.08	52.02	53.73
	LWAP [3]	$/MWh	83.46	68.73	50.55	46.68	61.49	62.00
	LWAP/GWAP	%	106%	107%	112%	119%	118%	115%
	Gas used in internal generation	PJ	3.1	3.1	3.1	2.1	2.2	2.1
	Wholesale gas sales	PJ	0.2	0.2	0.3	0.3	0.3	0.2
	Gas storage net movement	PJ	(0.2)	(0.1)	(0.0)	(0.1)	(0.6)	(0.7)
	Unit generation cost [4]	$/MWh	50.77	54.67	48.21	38.41	45.80	42.36
	Net purchase cost [5]	$/MWh	49.60	51.00	45.28	37.14	42.06	38.31
LPG	LPG sales	tonnes	7,313	6,724	6,083	6,151	5,345	5,192
	LPG customer numbers (includes franchises) [6]		62,000	62,000	62,500	62,500	63,000	63,000

Financial results summary

Key financial information	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	%
Revenue and other income	1,213	1,283	(70)	(5%)
Operating expenses (1)	(960)	(1,052)	92	9%
EBITDAF (2)	**253**	**231**	**22**	**10%**
Depreciation and amortisation	(95)	(95)	-	0%
Change in fair value of financial instruments	(1)	(10)	9	90%
Other significant items	(4)	(1)	(3)	(300%)
Equity accounted earnings of associate	-	2	(2)	(100%)
Earnings before net interest expense and tax	**153**	**127**	**26**	**20%**
Net interest expense	(33)	(37)	4	11%
Tax expense	(32)	(22)	(10)	(45%)
Profit for the period	**88**	**68**	**20**	**29%**
Statutory earnings per share (cents)	**12.2**	**9.7**	**2.5**	**25%**
Underlying earnings after tax (3)	**92**	**76**	**16**	**21%**
Underlying earnings per share (cents)	**12.7**	**10.9**	**1.8**	**17%**
Shareholders' equity	**3,497**	**3,309**	**188**	**6%**

(1) Includes electricity purchases.
(2) Earnings before net interest expense, tax, depreciation, amortisation, change in fair value of financial instruments and other significant items.
(3) Underlying earnings after tax is calculated by adjusting profit for the period for significant items that do not reflect the ongoing performance of the Group.

Integrated Energy segment result

Integrated Energy segment	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	%
Mass market electricity	515	494	21	4%
Commercial & industrial electricity	258	263	(5)	(2%)
Retail gas	39	38	1	3%
Steam	11	11	-	0%
Total revenue	**823**	**806**	**17**	**2%**
Net purchase cost	(222)	(249)	27	11%
Electricity networks, levies & meter costs	(295)	(273)	(22)	(8%)
Gas networks, levies & meter costs	(23)	(23)	-	0%
Total cost of goods sold	**(540)**	**(545)**	**5**	**1%**
Electricity and gas cost to serve	(52)	(52)	-	0%
EBITDAF	**231**	**209**	**22**	**11%**

Net purchase cost

Net purchase cost	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	%
Wholesale electricity revenue	297	393	(96)	(24%)
Wholesale gas revenue	15	12	3	25%
Total wholesale revenue	**312**	**405**	**(93)**	**(23%)**
Electricity purchases	(274)	(372)	98	26%
Other purchase costs	(14)	(16)	2	13%
Electricity transmission & levies	(20)	(17)	(3)	(18%)
Gas purchases	(141)	(160)	19	12%
Gas transmission & levies	(15)	(11)	(4)	(36%)
Emision costs	(3)	(13)	10	77%
Total direct costs	**(467)**	**(589)**	**122**	**21%**
Generation operating costs	(67)	(65)	(2)	(3%)
Net purchase cost	**(222)**	**(249)**	**27**	**11%**

Other segment result

Other segment	6 months ended 31 Dec 2012 $m	6 months ended 31 Dec 2011 $m	Variance $m	Variance %
LPG revenue	65	62	3	5%
Meter leases revenue	7	7	-	0%
Meter leases revenue - internal	17	17	-	0%
Other revenue	5	2	3	130%
Total other segment revenue	**94**	**88**	**6**	**7%**
LPG purchases	(48)	(44)	(4)	(9%)
Meter costs	(13)	(11)	(2)	(18%)
Total direct costs	**(61)**	**(55)**	**(6)**	**(11%)**
Other operating expenses	(11)	(11)	-	0%
EBITDAF	**22**	**22**	-	0%